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Petrophysical Evaluation of Well Logs from 'B' Oilfield, Onshore Niger Delta, Nigeria

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Abstract

This study analyzes and evaluates the petrophysical responses of the reservoir sands of 'B' field, onshore western Niger Delta. Petrophysical parameters such as permeability, porosity, net-to-gross, water saturation, volume of shale, and reservoir thickness were derived from well logs and their distributions across the reservoir were evaluated with the use of cross-plot relationship to characterize the petrophysical distribution of the study field. The average of computed gamma ray index (IGR), volume of shale (Vsh), total porosity (Poro-T), effective porosity (Poro Eff), water saturation, (Sw) net-to-gross (NTG), irreducible water saturation (Swirr) and permeability (k) with respect to each reservoir was 64%, 69%, 6.0%, 18.0%, 11.0%, 99.0%, 14.0%, and 1324.30mD respectively. A correlation coefficient ranging from 0.7 - 0.9 was obtained for effective porosity values within the reservoir sands in the study field. A litho-stratigraphic correlation of the intervals, using determined petropyhsical properties, within the four wells helped identification of the environments of deposition throughout the wells. Delineation of the lateral continuity, geometry and internal architecture of the reservoir sand bodies using available well log suites were also observed as a result of this high-resolution correlation of the respective reservoirs.

Keywords: Petrophysics, well logs, correlation, porosity, permeability, Greater Ughelli depobelt.

Introduction

The study area, 'B' Field is located within the Greater Ughelli Depobelt of the Niger Delta region. It lies between longitudes 5.06°E and 7.37°E and latitudes 4.16°N and 6.03°N (Fig.1) on the onshore part of the Niger Delta province. The Cenozoic Niger Delta is situated at the intersection of the Benue Trough and the South Atlantic Ocean where a triple junction developed during the separation of South America and Africa in the Late Jurassic time (Whiteman, 1982). The objective of oil and gas operation is to find, extract, refine and sell oil and gas, refined products and related products. It requires substantial capital investment and long lead times to find and extract the discovered hydrocarbons. Since reserve is the greatest

asset of the industry, there is need to estimate the hydrocarbon in place from onset in order to determine economically whether further development plans should be carried out on a field or not. Estimation of hydrocarbon in place is one of the major problems faced by the petroleum industry. Reserves estimation of a discovery are usually carried out as an integrated studies by petrophysicists, petroleum engineers, geologists and with an array of other relevant professionals within the industry.

Fig. 1. Location map of the Niger Delta showing 'B'- Well.

It is theoretically possible to say a reservoir contains hydrocarbon, but it becomes somewhat difficult to envisage the hydrocarbon in-place volume, ultimate recoverable volume, and the type of hydrocarbon without properly analyzing and evaluating the petrophysical parameters. This requires analysis of measured information with respect to the geology of the reservoir, the surrounding rock formations and the analysis of the fluids and gases within the reservoir through logging. The measurements in boreholes correspond to a set of techniques whose purpose is to obtain local information on the formations being drilled, the fluids that they contain and the state of the well. However, this information can confirm or not the surface studies. The direct information (cuttings, cores, fluid samples) is always insufficient, so it needs to be supplemented by a whole series of downhole operations called logging or otherwise termed petrophysical evaluation. Hydrocarbon in place estimation begins with identifying a drillable prospects and it continues while the prospect is developed and placed on production, and thereafter as warranted by well and/or reservoir performance, new geologic data, competitor operations, utilization, contract negotiation, improved technology and changing economic conditions. It is the process by which the economically recoverable hydrocarbons in a field are evaluated quantitatively.

Reserve estimation is more than periodically or statutorily calculating and reporting of the company assets. It is an essential element of investment planning and resource management for the operators. A discovery is a known accumulation(s) or hydrocarbons in-place. It has been penetrated by a wellbore and the resulting analysis of well logs, cores or formation tests indicates that significant hydrocarbons exist and are potentially recoverable. The need for reducing risk in oil filed development has been the drive for logging companies to develop equipment capable of precisely analyzing reservoir characteristics in order to estimate the volume of oil in place with the best possible accuracy. Directly deriving from the above, it can be concluded that the productivity of wells in a hydrocarbon-bearing reservoir depends on petrophysical properties. Hydrocarbon bearing reservoir rock consists of two components which include the rock matrix and interconnected pores in which their dimensions vary from sub-microns for tight sandstones to centimeter for vuggy carbonate rocks (Levorsen, 1967).

Theoretically, it is possible to say a reservoir contains hydrocarbon and this confirmation requires analysis of measured information about the reservoir geology, surrounding the rock formations and analyzing the reservoir fluids through logging using standard log motif (Fig. 2). Formation evaluation presupposes that

a reservoir has been located and is to be defined by drilling the least number of wells possible (Sengel, 1983). Enough data should be gathered from those wells to extrapolate reservoir parameters field wide and to arrive at realistic figures for both the economic evaluation of the reservoir and the planning of the optimum recovery method.

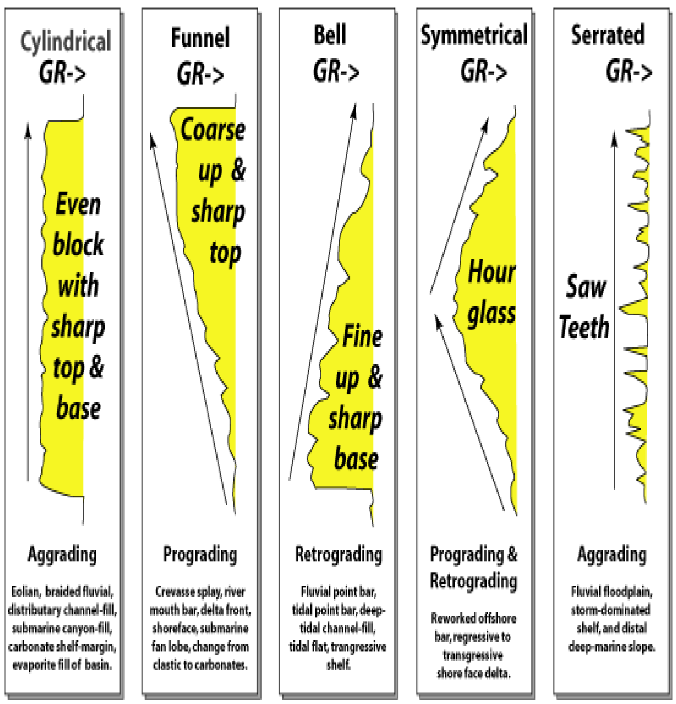

Fig. 2. Standard log motifs, gamma ray response to grain size variations (Modified from Emery and Myers, 1997).

In the present work, composite log suites are used to characterize and evaluate the subsurface for hydrocarbon potentials of 'B' field, onshore Niger Delta. The aim of the study include estimation of the reservoir statistical parameters such as net-to-gross, reservoir gross sand thickness, net pay as well as fluid contacts of all the wells provided. It will also use all the available petrophysical parameters mentioned above to estimate the respective hydrocarbon bearing sands of interest across the wells. This will help in further identifying the hydrocarbon reservoirs horizons thereby evaluating its properties using petrophysical parameters.

Geologic setting and Stratigraphy

The Niger Delta which is situated in the Gulf of Guinea is one of the most prolific hydrocarbon belts in the world. This delta derives its origin from the Paleocene sediments to the present, the delta has prograded southwestward, forming depobelts that represent the most active portion of the delta at each stage of its development (Doust and Omatsola, 1990). Geographically, the Niger Delta is located between longitudes 5^0 and 8^0E and latitudes 3^0 and 6^0N respectively. The basin occupies a total area of 7,500km^2 in the Gulf of Guinea with a sediment thickness of 12,000m or equivalent (Bustin, 1988). The influence of basement tectonics on the structural evolution of the Niger Delta was largely limited to movement along the Equatorial Atlantic Ocean fracture zones that later extended beyond or beneath the delta (Burke, 1972). Growth faults, triggered by pen-contemporaneous deformation of deltaic sediments are the dominant structural features in the Niger delta (Weber, 1987). They are generated by rapid sedimentation load and the gravitational instability of the Agbada sediments pile accumulating on the mobile, uncompacted Akata shales (Weber, 1987).

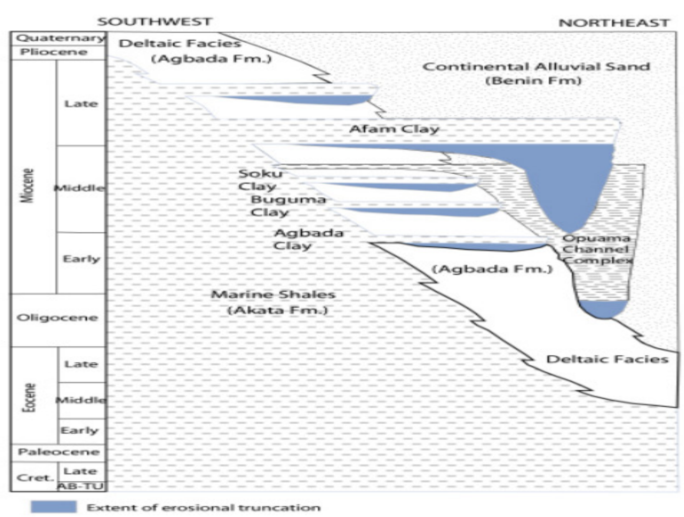

Fig. 3. Stratigraphic column showing the three formations of the Niger delta (After Doust and Omatsola, 1990).

Lithostratigraphically, the Tertiary Niger Delta was deposited in three major sequences which have been shown by well sections drilled vertically within this environment (Fig. 3). The Niger Delta Province contains only one identified petroleum system (Ekweozor and Daukoru, 1994). The Tertiary section of the Niger Delta is divided into three formations (Fig. 4), representing prograding depositional facies that are distinguished mostly on the basis of sand-shale ratio. The type sections of these formations are described by Short and Stauble (1965).

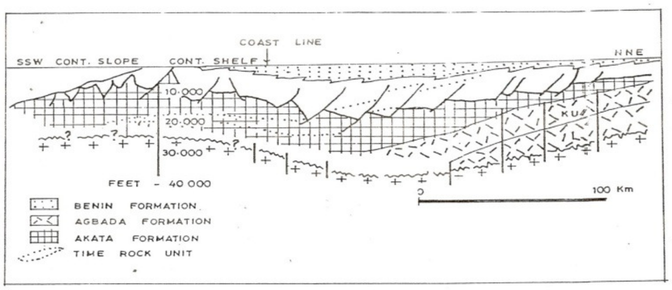

Fig. 4. Niger Delta schematic dip section (After Merki, 1970).

These three major lithostratigraphic units are locally designated in ascending order as Akata Formation (prodelta), Agbada Formation (delta front) and Benin Formation (delta plain). The Benin Formation which is dated Oligocene to Recent in age is directly overlying the Agbada Formation in the continental upper deltaic plain. It has been described as coastal plain sands and outcrops extensively (Reyment, 1965). The formation consists of fresh water, fluviatile sands and gravels with occasional coal seams, lignites and shale deposits of Miocene to Recent age whose thickness are variable but generally exceed 1,970 meters (about 6,000 feet) (Asseez, 1989). Also, it consists of about ninety percent freshwater continental sands and gravel which are massive, porous with clay and shale intercalations (Allen, 1965). Presently, only very little oil has been found in the Benin Formation (mainly minor oil shows) and the formation is generally water bearing making it the main source of portable ground water in the Niger Delta (Etu-Efeotor, 1997).The Benin Formation has 9:1 sand/shale ratio interbeds (Evamy et al., 1978). The sand varies in grain size from fine to very coarse and in some places pebbly.

The Agbada Formation is of Eocene age and is overlain by the continental sand sequence of the Benin Formation. It is grossly growth faulted with the associated development of rollover anticlines that constitute ninety percent (90%) of the petroleum reservoir rocks in the Niger Delta (Avbovbo, 1978). It is diachronous with a thickness of about 4500m. It ranges in age from Upper Miocene in the north to Pliocene – Pleistocene in the south. Avbovbo (1978) found that the sands of the Agbada Formation are the main reservoirs in the Niger delta with shale providing the lateral and vertical seal. The shales on the other hand are dark grey, hard and sub-fissile to fissile with occasional shell fragments. The shale of the lower Agbada Formation has the potentials for hydrocarbon generation (Ekweozor and Okoye, 1980).The Agbada Formation consists of alternating, deltaic (fluviatile, coastal, fluvio-marine) sands and shales ranging in thickness from 305 – 4,572m (Schield, 1978). The Formation is a sequence of sandstones and shales. This formation is essentially a cyclic succession of poorly consolidated, porous, permeable and friable sandstones and shales representing paralic deposits of the delta front megafacies (Stacher, 1995).

The basal sedimentary unit of the Niger Delta is the Akata Formation. This formation is overlain by the paralic sand/shale sequence of the Agbada Formation representing 3:2 ratio of sand to shale (Evamy et al., 1978). The paralic sand/shale succession in this formation is attributed to the differential subsidence of these sediments and shifts of the delta depositional axes which cause local transgressions and regressions. The Akata Formation has a clastic thickness of about 6000m (Beka and Oti, 1995). This formation is composed of shales, generally dark to light grey in colour and sandy to silty in places (Asseez, 1976). Within this formation there are traces of plant remains

and mica minerals however, this formation is rich in microfauna contents. The benthonic foraminiferal assemblage in the formation indicates that the sediments were deposited on shallow marine shelf as a pre-deltaic sequence. The shales lithofacies within this formation are principally uncarpeted and highly pressured (Knox and Omatsola, 1989). The Akata Formation depicts a marine origin which is composed of turbidite sand (potential reservoirs in deep water), thick shale sequences (potential source rock) and minor amounts of silt and clay. From the Paleocene to Recent, the formation was formed during lowstands probably when terrestrial organic matter and clays were transported to deep water areas characterized by low energy conditions and oxygen deficiency. The structural elevation of the base of the Agbada Formation fluctuates widely throughout the delta due to the sedimentary diapirism and was found largely within the Akata shale with consequent growth fault development (Michele et al, 1999).

Materials and Method

The datasets provided for this study include deviation surveys for four wells, suites of well logs for four wells. For the purpose of this study the field is referred to as 'B' field and wells are pseudo-named CPG-01, CPG-02, CPG-03 and CPG-04 respectively. The well logs data employed in this study include Gamma ray, Caliper, Resistivity, Spontaneous potential, Bulk density and Sonic respectively. However, not all the wells have all the mentioned log types enumerated above. For example well CPG-01 has Caliper, Gamma ray, Resistivity, Neutron porosity and Spontaneous potential logs, while CPG-02 has Gamma ray, Resistivity, Spontaneous potential and Sonic logs. Wells CPG-04, CPG-05 and CPG-06 have all the logs earlier mentioned with inclusion of bulk density log. In addition, wells CPG-01and CPG-04 have water saturation logs. The workflow chart (Fig. 5) used in this study is presented below:

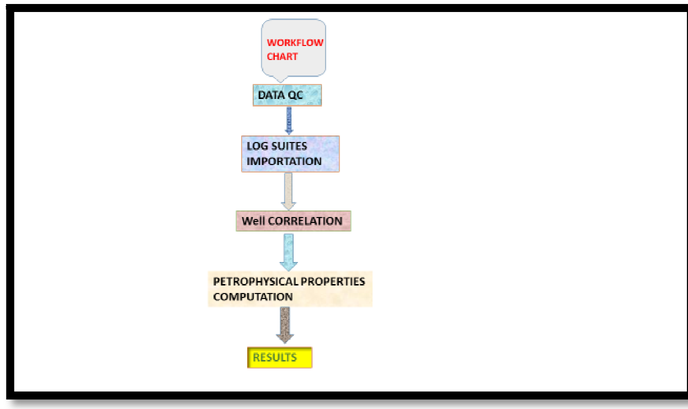

Fig. 5. Petrophysical workflow chart.

The data quality control was carried out before the data were imported into the Schlumberger Petrel software. Afterwards, correlation of all the wells was undertaken while Powerlog software was employed for the petrophysical parameter evaluations. Well header information file containing the co-ordinates was loaded into petrel software while the well log suites were loaded thereafter in order to display the wells within their proper co-ordinates. Deviation survey, which measures the deviation of the wells from the vertical were also imported into the Petrel software. A base map of the study area as shown in Figure 6 was generated after loading all the data as mentioned above.

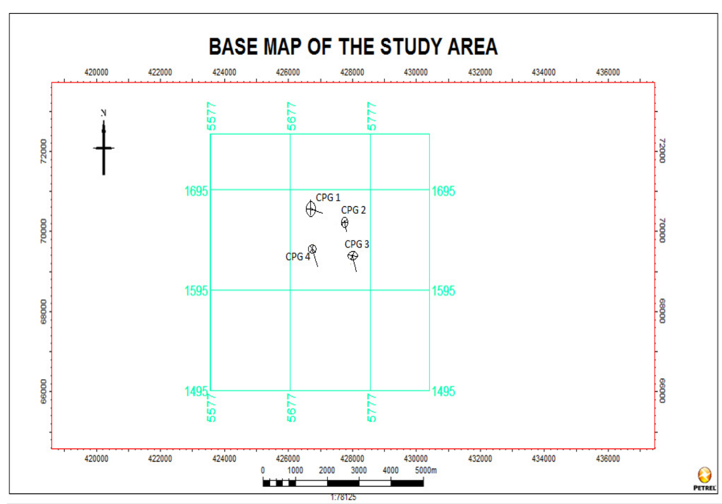

Fig. 6. Base map of the study area.

Results and Discussion

Four wells were provided and evaluated for their petrophysical parameters in this study. A detailed petrophysical evaluation was carried out on each of four reservoir units of interest which were found laterally traceable across all four wells. For this study, all four reservoir sand bodies from the top horizon are labeled M1, M7, M8 and M9 respectively. These reservoir horizons were all found within the correlation panel which utilizes the well logs motifs encountered within the analyzed wells (Fig. 7a, 7b). All the computed petrophysical /statistical parameters for the four horizons analyzed in this study are presented in Table 4.1 – 4.4.

Well logs were used to identify different lithofacies and environments of deposition present within the study area. Gamma ray (GR) logs were used as the primary tools for lithology identification and delineations. Correlation of the wells in this study has been attempted however, inference drawn from the correlation panel on figure 7a shows that Reservoir M1 encountered upper shoreface sand, probably with a depth range of 3018.84 – 2955.33m resulting in a thickness of about 63.51m. The observed sediments thins out from CPG-4 to CPG-3 wells. Well CPG-3 is totally shaly within this horizon or may have been observed to admixture hot sand sediments. However apart from well CPG-3, other wells exhibited high resistivity within this horizon therefore the choice of analysing this horizon for hydrocarbon.

Similarly in Figure 7b, the reservoir M7 sand body horizon occurred at a depth range of 3414.70 – 3381.10m with a thickness of about 33.60m. Upper and lower shoreface sands and heterolithics occurred with minor channel fill sediments. It has been observed that CPG-3 well occurred on the upthrown of well CPG-1, CPG-2 and CPG-4 wells respectively. Reservoir M8 equally showed similar facies as recorded by the overlying horizon and was observed to occur within a depth range of 3457.46 – 3428.51m exhibiting a thickness of 28.95m. The shales observed in between this horizon across all the wells probably acts as a baffle. In reservoir M9, the horizon occurred at a depth range of 3571.18 – 3494.32m with a thickness of 76.86m. This horizon shows a multistorey channel sediments deposition admixture upper and lower shoreface sands with heterolithics facies.

CPG 1 Well

Reservoir M1

The reservoir occurs at the depth range of 2955.33 – 3018.84mah (along hole) with a thickness of about 63.51m. The porosity values of the reservoir range from 0.1 – 38.0% with an average value of 12.0%. The observed permeability within this reservoir ranges from 625.08 - 4251.04mD with average value of 1467.30mD. On the other hand, it was observed that the water saturation values found within the CPG-1 reservoir range from 21.2 – 73.10% with an average value of 44.0%. The irreducible water saturation values of the reservoir on the other hand range from 5.1 – 19.20% with an average value of 11.0% (this is a water-wet reservoir; although pressure data and special core analysis (SCAL), would give better a confirmation). The volume of shale values of the reservoir ranges from 0 – 99.6% with an average value of 44%.

Deductions from the above analyses indicate that the reservoir has negligible to excellent porosity and excellent permeability. Conversely in Vsh vs Poro Eff vs Perm, it showed that as Vsh decreases Poro Eff. increases and permeability somewhat increases. Inference drawn from the analogous is that, better sands are penetrated as we go down the well. However, Poro Eff vs Sw signified that with increasing Poro Eff, there is reduction in Sw and vice versa. Hence some reservoirs are better than some owing to the geologic process at the time of sedimentation and subsequent diagenesis.

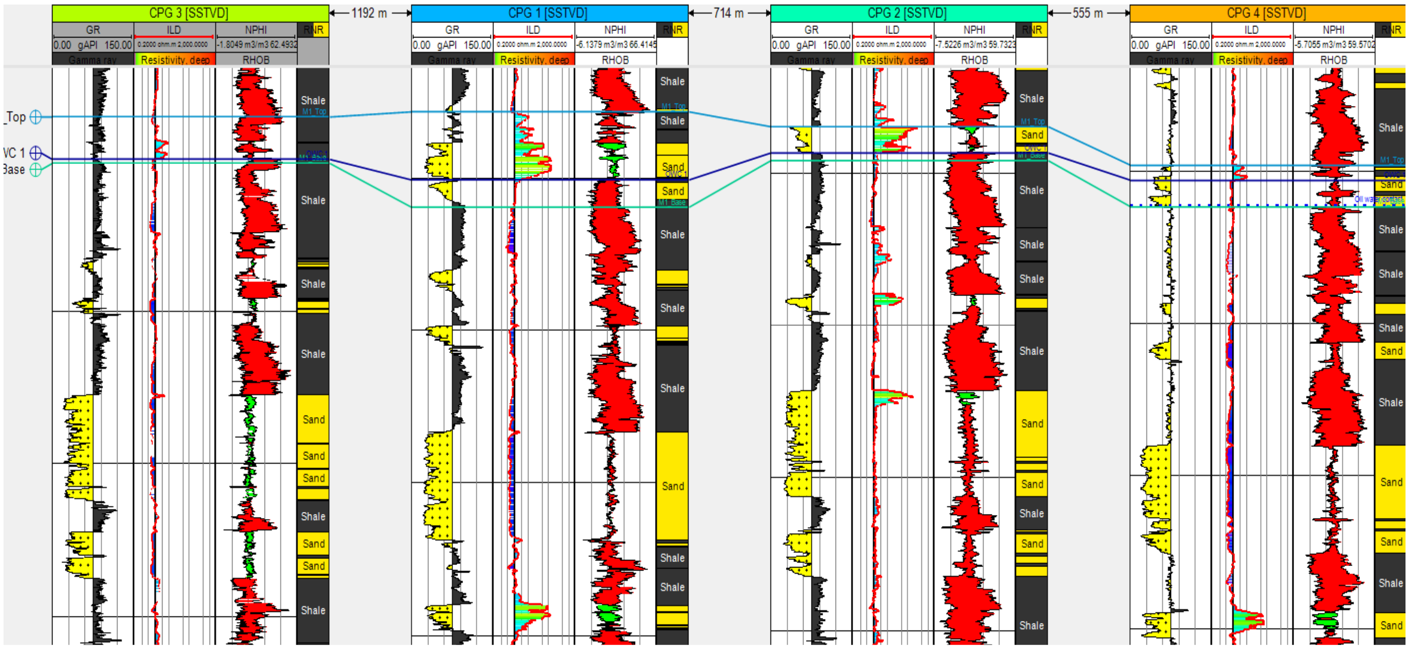

Fig. 7a: Correlation panel showing zones of the delineated reservoirs on the well section.

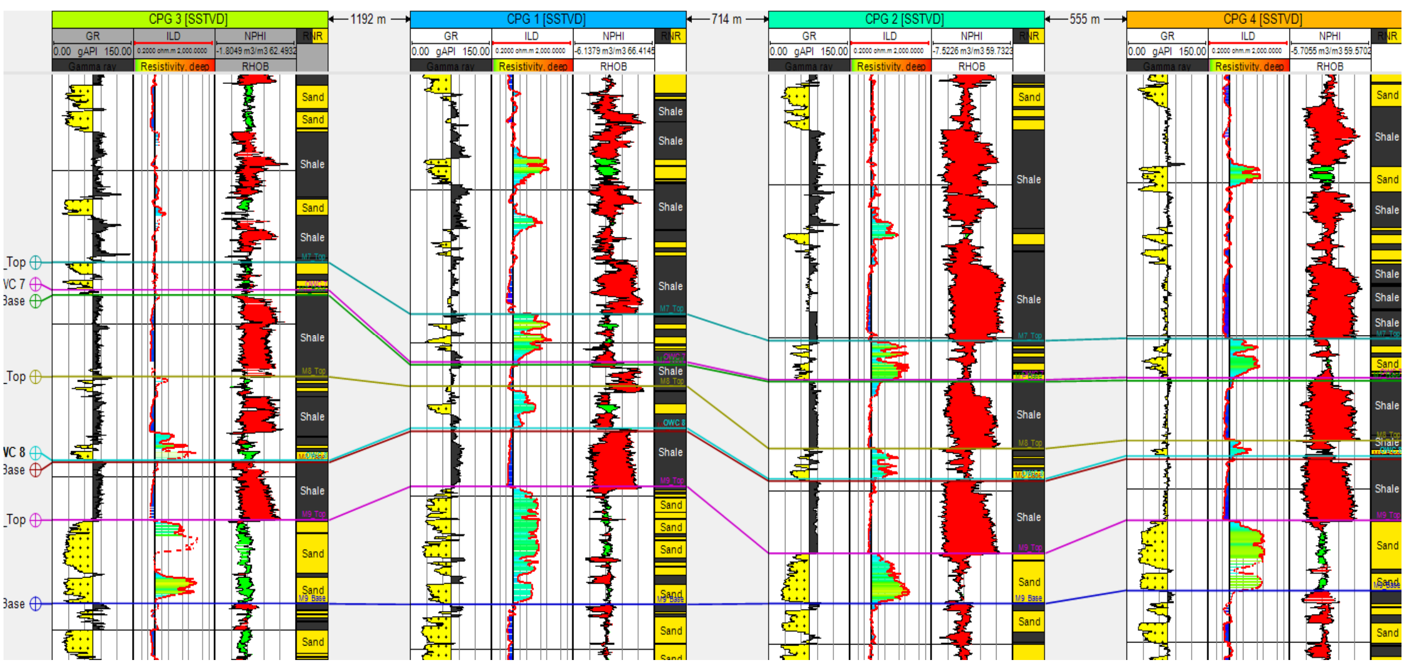

Fig. 7b. Correlation panel showing zones of the delineated reservoirs on the well section.

Reservoir M7

This reservoir horizon occurs at the depth range of 3381.10 – 3414.70mah (meter along hole). It has a thickness of 33.60m. The porosity values of the reservoir range from 4.9 – 33.90% with an average value of 16%. The permeability within this reservoir ranges from 705.06 - 5141.24mD with average value of 1875.02mD. The water saturation values of the reservoir range from 19.2 – 65.70% with an average value of 38.0%. The irreducible water saturation

values of the reservoir range from 4.6 – 17.10% with an average value of 9.0% while the volume of shale values obtained for this reservoir ranges from 6.7 – 62.80% with an average value of 32.0%.

The result from this zone indicates that the reservoir has negligible to excellent porosity and excellent permeability.

Table 4.1. Computed Petrophysical / Reservoir Statistical Parameters for CPG 1.

Properties	Reservoir M1	Reservoir M7	Reservoir M8	Reservoir M9
IGR (%)	67.00	60.00	52.00	51.00
Vsh (%)	44.00	32.00	29.00	29.00
Poro T (%)	20.00	23.40	22.50	20.00
Poro Eff (%)	12.00	16.00	17.00	15.00
Sw (%)	44.00	38.00	39.00	44.00
Facies	100.00	100.00	100.00	100.00
Swirr	11.00	9.00	9.00	11.00
Perm (mD)	1467.30	1875.02	1725.19	1450.79

WELL/ RESERVOIR STATISTICS

CPG 1	Formation Top (m)	Formation Bottom (m)	Gross Reservoir thickness (m)	Net Reservoir Thickness (m)	Net / Gross
M 1	2995.33	3018.84	23.51	23.27	0.99
M 7	3381.10	3414.70	33.60	33.60	1.00
M 8	3428.51	3457.46	28.95	28.95	1.00
M 9	3494.32	3571.18	76.86	76.86	1.00

Reservoir M8

Reservoir M8 occurs at the depth range of 3428.51 – 3457.46mah with an overall thickness of 28.95m. The porosity values of the reservoir range from 4.9 – 33.90% with an average value of 17%. The permeability value ranges from 436.75 – 3406.75mD with average value of 1725.19mD. The water saturation value of the reservoir ranges from 23.9 – 100% with an average value of 39.0%. The irreducible water saturation values of the reservoir range from 5.8 – 29.90% with an average value of 9.0%. The volume of shale values of the reservoir ranges from 0.2 – 62.90% with an average value of 29.0%.

This indicates that the reservoir has negligible to excellent porosity and excellent permeability.

Reservoir M9

This reservoir occurs at the depth range of 3494.32 – 3571.18mah. However, the reservoir has a thickness of 76.86m. The porosity values of the reservoir range from 4.5 – 29.10% with an average value of 15.0%. Its permeability ranges from 509.57 – 5406.09mD with average value of 1450.79mD. The water saturation values of the reservoir range from 18.7 – 90.30% with an average value of 44.0%. The irreducible water saturation values of the reservoir range from 4.4 – 24.10% with an average value of 11% while the volume of shale values of the reservoir ranges from 0.2 – 66% with an average value of 29.0%. This indicates that the reservoir has negligible to excellent porosity and excellent permeability.

CPG 2 Well

Reservoir M1

This reservoir occurs at the depth range of 2969.16 – 2991.49mah and shows a thickness of about 22.33m. The porosity values of the reservoir range from 2.6 – 33.20% with an average value of 12% while permeability parameters ranges from 521.48 – 3260.77mD with average value of 1334.69mD. The water saturation values of the reservoir range from 24.50 – 87.90% with an average value of 49%. The irreducible water saturation values of the reservoir were observed to range in value from 5.90 – 23.40% with an average value of 13.0%. The volume of shale computed shows that the values within the reservoir ranges from 0.6 – 74.0% with an average value of 42.0%. This indicates that the reservoir has negligible to excellent porosity and excellent permeability when compared to standard values for these parameters.

Table 4.2. Computed Petrophysical / Reservoir Statistical Parameters for CPG 2.

Properties	Reservoir M1	Reservoir M7	Reservoir M8	Reservoir M9
IGR (%)	65.00	72.00	79.00	54.00
Vsh (%)	42.00	51.00	59.00	37.00
Poro T (%)	18.60	17.20	15.60	12.60
Poro Eff (%)	12.00	10.00	7.00	9.00
Sw (%)	49.00	49.00	55.00	73.00
Facies	100.00	100.00	100.00	100.00
Swirr	13.00	13.00	14.00	19.00
Perm (mD)	1334.69	1121.59	974.33	773.61

WELL /RESERVOIR STATISTICS

CPG 2	Formation Top (m)	Formation Bottom (m)	Gross Reservoir thickness (m)	Net Reservoir Thickness (m)	Net / Gross
M 1	2969.11	2991.49	22.38	22.38	1.00
M 7	3402.31	3428.68	26.30	26.30	1.00
M 8	3472.16	3498.53	26.37	26.37	1.00
M 9	3540.78	3573.68	32.90	32.90	1.00

Reservoir M7

The reservoir occurs at the depth range of 3402.31 – 3428.61mah. The reservoir has a thickness of 26.30m with a porosity values of the reservoir ranging from 3.6 – 26.1%; an average value of 10%. The permeability ranges from 554.88 – 2559.99mD with average value of 1121.59mD. The water saturation values of the reservoir range from 24.5 – 87.9% with an average value of 49.0%. The irreducible water saturation values of the reservoir range from 7.4 – 21.8% with an average value of 13%. The volume of shale values of the reservoir ranges from 9.6– 99.6% with an average value of 59.0%. This indicates that the reservoir has negligible to excellent porosity and excellent permeability.

Reservoir M8

The reservoir occurs at the depth range of 3472.16 – 3498.53mah. The reservoir has a thickness of 26.37m while the porosity values of the reservoir was observed to range from 0.05 – 21.50% with an average value of 7%. The permeability ranges from 368.46 –1814.34mD with average value of 974.33mD. The water saturation values of the reservoir range from 34.3 – 150% with an average value of 55%. And conversely, the irreducible water saturation values of the reservoir range from 8.5 – 41.6% with an average value of 14.0%. The volume of shale values of the reservoir ranges from 0.2 – 62.9% with an average value of 29%. This indicates that the reservoir has negligible to very good porosity and excellent permeability.

Reservoir M9

The reservoir occurs at the depth range of 3540.78 – 3573.68mah. The reservoir has a thickness of 32.90m. The porosity values of the reservoir range from 2.3 – 21.70% with an average value of 9.0%. The parameter calculated for the permeability with the reservoir ranges from 379.34 – 1579.72mD with average value of 773.61mD. The water saturation values of the reservoir ranges from 37.2– 140.8% with an average value of 73%. The irreducible water saturation values of the reservoir range from 9.3 – 38.9% with an average value of 19%. The volume of shale values of the reservoir ranges from 0 – 68.9% with an average value of 37%.The overall result indicates that the reservoir has negligible to very good porosity and excellent permeability.

CPG 3 Well

Reservoir M1

The reservoir occurs at the depth range of 2971.82 – 3002.29mah and shows a thickness of 30.74m. However, the porosity values of the reservoir range from 8.6 – 18.5% with an average value of 13%. It was observed that the permeability of this reservoir horizon ranges from 747.60 – 2073.55mD with average value of 1226.20mD. The water saturation values of the reservoir range from 31.70 – 62.6% with

an average value of 44%. The irreducible water saturation values of the reservoir range from 7.8 – 16.3% with an average value of 11.0%. The volume of shale values of the reservoir ranges from 11 – 50.50% with an average value of 29%. This indicates that the reservoir has poor to good porosity and excellent permeability.

Table 4.3. Computed Petrophysical / Reservoir Statistical Parameters for CPG 3.

Properties	*Reservoir M1*	*Reservoir M7*	*Reservoir M8*	*Reservoir M9*
IGR (%)	58.00	60.00	50.00	50.00
Vsh (%)	29.00	32.00	23.00	23.00
Poro T (%)	18.60	18.70	21.20	19.10
Poro Eff (%)	13.00	17.00	16.00	15.00
Sw (%)	44.00	45.00	39.00	44.00
Facies	100.00	100.00	100.00	100.00
Swirr	11.00	11.00	10.00	11.00
Perm (mD)	1226.20	1253.94	1521.77	1275.76

WELL/ RESERVOIR STATISTICS

CPG3	*Formation Top (m)*	*Formation Bottom (m)*	*Gross Reservoir thickness (m)*	*Net Reservoir Thickness (m)*	*Net / Gross*
M 1	2971.82	3002.29	30.47	30.47	1.00
M 7	3360.04	3381.36	21.32	21.32	1.00
M 8	3434.89	3490.40	55.51	55.51	1.00
M 9	3528.07	3562.10	34.03	34.03	1.00

Reservoir M7

The reservoir occurs at the depth range of 3360.04 – 3381.36mah with a thickness of 21.32m. The porosity values of the reservoir range from 7.6 – 28.60% with an average value of 17.0%. The permeability ranges from 612.88 – 3240.36mD with average value of 1253.94mD. The water saturation values of the reservoir range from 24.6 – 74.50% with an average value of 45.0% while the irreducible water saturation values of the reservoir range from 5.9 – 19.60% with an average value of 11%. The volume of shale values of the reservoir ranges from 15.3– 99.6% with an average value of 32.0%. This inference indicates that the reservoir has poor to excellent porosity and excellent permeability.

Reservoir M8

The reservoir occurs at the depth range of 3434.89 – 3490.40mah and showed a thickness of 55.51m. The porosity values of the reservoir range from 7.6 – 34.10% with an average value of 16%. However, the permeability ranges from 684.76 –5142.62mD with average value of 1521.77mD. The water saturation values of the reservoir range from 19.2 – 67.3% with an average value of 39.0% while the irreducible water saturation values of the reservoir was found to range from 4.6 – 17.6% with an average value of 10.0%. The volume of shale values of the reservoir ranges from 0 – 58.4% with an average value of 23%. The overall result indicates that the reservoir within this horizon exhibited poor to excellent porosity and excellent permeability.

Reservoir M9

The reservoir occurs at the depth range of 3528.07 – 3562.10mah and has a thickness of 34.03m. The porosity values of the reservoir range from 8.2 – 23.4% with an average value of 15.0%. The permeability ranges from 558.44 – 2169.03mD with average value of 1275.76mD. The water saturation values of the reservoir range from 30.8– 81.7% with an average value of 44.0%. However, the irreducible water saturation values of the reservoir range from 7.6 – 21.70% with an average value of 11.0%. The volume of shale values of the reservoir ranges from 0.2 – 36.90% with an average value of 23.0%. This analysis indicates that the reservoir has poor to very good porosity and excellent permeability.

CPG Well 4

Reservoir M1

The reservoir occurs at the depth range of 2995.94– 3023.20m. The reservoir has a gross thickness of

27.26m, net thickness of 24.53m and net-to-gross of 99.0%. The porosity values of the reservoir range from 0.1 – 19.9% with an average value of 6.0%. The permeability ranges from 733.75 – 2469.49mD with average value of 1272.65mD. The water saturation values of the reservoir range from 28.60 – 63.50% with an average value of 45.0%. The irreducible water saturation values of the reservoir range from 7.0 – 16.50% with an average value of 11.0% (this is a water-wet reservoir, although pressure data and special core analysis would give better confirmation). The volume of shale values of the reservoir ranges from 29.9 – 99.60% with an average value of 69.0%. This indicates that the reservoir has negligible to good porosity and excellent permeability.

Table 4.4. Computed Petrophysical / Reservoir Statistical Parameters for CPG 4.

Properties	Reservoir M1	Reservoir M7	Reservoir M8	Reservoir M9
IGR (%)	87.00	86.00	87.00	57.00
Vsh (%)	69.00	67.00	68.00	40.00
Poro T (%)	18.90	16.40	13.40	17.40
Poro Eff (%)	6.00	5.00	4.00	12.00
Sw (%)	45.00	50.00	63.00	54.00
Facies	100.00	100.00	100.00	100.00
Swirr	11.00	13.00	16.00	14.00
Perm (mD)	1272.65	1016.52	784.53	1211.31

WELL /RESERVOIR STATISTICS

CPG4	*Formation Top (m)*	*Formation Bottom (m)*	*Gross Reservoir thickness (m)*	*Net Reservoir Thickness (m)*	*Net / Gross*
M 1	2995.94	3023.20	27.26	26.99	0.99
M 7	3402.14	3429.04	26.90	26.90	1.00
M 8	3468.18	3480.41	12.23	12.23	1.00
M 9	3520.03	3566.02	45.99	45.99	1.00

Reservoir M7

The reservoir occurs at the depth range of 3402.14 – 3429.04m. The reservoir has a gross thickness of 26.90m, net thickness of 26.90m and net-to-gross of 100%. The porosity values of the reservoir range from 0.2 – 9.20% with an average value of 5.0%. The permeability ranges from 667.27 – 1647.25mD with average value of 1016.52mD. The water saturation values of the reservoir range from 36.3 – 68.90% with an average value of 50.0%. The irreducible water saturation values of the reservoir range from 9.1 – 18.0% with an average value of 13% (this is a water-wet reservoir, although pressure data and special core analysis would give better confirmation). The volume of shale values of the reservoir ranges from 42.3– 99.10% with an average value of 67.0%. This indicates that the reservoir has negligible to poor porosity and excellent permeability. The fact that, the better the porosity, the better the permeability does not hold in this case. However, this reservoir possesses an excellent permeability with negligible to poor porosity. With negligible to poor porosity, the excellent the permeability.

Reservoir M8

The reservoir occurs at the depth range of 3468.18 – 3480.41m. The reservoir has a gross thickness of 12.23m, net thickness of 12.23m and net-to-gross of 100%. The porosity values of the reservoir range from 1.5 – 6.90% with an average value of 16%. The permeability ranges from 427.71 –1066.40mD with average value of 784.53mD. The water saturation values of the reservoir range from 48.0 – 113.80% with an average value of 63.0%. The irreducible water saturation values of the reservoir range from 12.2 – 30.90% with an average value of 16.0% (this is a water-wet reservoir, although pressure data and special core analysis would give better confirmation). The volume of shale values of the reservoir ranges from 51.8 – 82.70% with an average value of 68.0%. This indicates that the reservoir has negligible to poor porosity and very good permeability.

Reservoir M9

The reservoir occurs at the depth range of 3520.03 – 3566.02m. The reservoir has a gross thickness of

45.99m, net thickness of 45.99m and net-to-gross of 100%. The porosity values of the reservoir range from 0.9 – 29.90% with an average value of 12.0%. The permeability ranges from 429.59 –2739.17mD with average value of 1211.31mD. The water saturation values of the reservoir range from 27.0– 113.0% with an average value of 54.0%. The irreducible water saturation values of the reservoir range from 6.6 – 30.70% with an average value of 14.0% (this is a water-wet reservoir, although pressure data and special core analysis would give better confirmation). The volume of shale values of the reservoir ranges from 0 – 89.60% with an average value of 40.0%. This indicates that the reservoir has negligible to excellent porosity and excellent permeability.

Conclusion

A correlation of the petrophysical logs show the presence of multiple reservoirs system delineated across the wells studied. However, inference obtained from the petrophyscial analysis results points to a prolific setting based on the parameters observed for the respective porosity, permeability, net-to-gross, water saturation and irreducible water saturation of all the wells under study. The encountered reservoir sands of the wells were interpreted as predominantly Upper shoreface sands admixture stacked channel fill deposits while minor shales in between the sand bodies acts as baffles.

Results and interpretation carried out on M1 reservoir showed that this horizon has been considered the best reservoir because of its peculiar characteristics in terms of porosity and permeability values.

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